Q. PLEASE STATE FOR THE RECORD YOUR NAME, BUSINESS ADDRESS AND OCCUPATION?

A. My name is Roy H. Barnette. My business address is 101 Executive Center Drive, Columbia, South Carolina. I am employed by the Public Service Commission of South Carolina as an Auditor.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. Following a six year enlistment in the United States Marine Corps, I received a B. S. Degree in Business Administration with a major in Accounting from the University of South Carolina in 1968. From 1968 to 1971 I was employed with S. D. Leidesdorf and Company, a national CPA firm in Charlotte, North Carolina. In 1972 I entered the private business sector. My most recent position was with Bagnal Builders Supply Co. Inc., here in Columbia, where I served as Senior Vice President and Chief Financial Officer from 1972 until September 1999 when I joined the Audit Staff of this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY INVOLVING PIEDMONT NATURAL GAS COMPANY, INC?

A. The purpose of my testimony is to present the Audit Staff’s findings and recommendations resulting from our review of the Company's deferred cost of gas account #253.04.

Q. IN CONNECTION WITH YOUR TESTIMONY, DID YOU PREPARE OR CAUSE TO BE PREPARED ANY EXHIBITS?

A. Yes, the Audit Staff has prepared Audit Exhibits A, A-1 and A-2 in connection with this testimony.

Q. ON WHAT AUTHORITY DOES THE STAFF MONITOR THE ACTIVITY IN PIEDMONT'S DEFERRED COST OF GAS ACCOUNT #253.04?

A. In Docket No. 83-126-G and 86-217-G, Order No. 88-294, the Commission found that:

(1) A true-up for differences between billed and filed rates is appropriate and necessary to assure that Piedmont's customers pay no more than Piedmont's actual cost of gas.

(2) A true-up of demand charges for changes in sales volumes is appropriate and necessary to assure that Piedmont's customers pay no more than Piedmont's actual cost of gas.

(3) The Company is to maintain an account reflecting its gas costs each month, the amount of gas costs recovered each month, and amounts deferred from month to month. The Company was also required to

file with the Commission a report on a monthly basis showing the status of this account.

(4) Additionally, with the issuance of Order No. 2002-223 dated March 26, 2002 in Docket No. 2001-410-G, the Company was required to file regular reports on the status of the hedging program and the results of its hedging activities.

Q. HAS STAFF CONDUCTED THE COMMISSION REQUIRED AUDIT OF THE COMPANY'S DEFERRED COST OF GAS?

A. Yes. The Audit Staff has reviewed the monthly filings made by the Company and the activity included in Deferred Cost of Gas account #253.04 and Account # 191.01 (Deferred Account-Hedging Program) for the period April 2003 through March 2004 as summarized on Audit Exhibits A, A-1 and A-2.

Q. PLEASE EXPLAIN THE FORMAT USED IN AUDIT EXHIBIT A.

A. Audit Exhibit A's format is as follows:

Billed vs. Filed Rates– These amounts represent the difference in the Company’s actual gas costs on a monthly basis as compared to the benchmark cost of gas included in the Company’s most recent GCRM (Gas Cost Recovery Mechanism) on file with the Commission. Effective April 1, 2003, the Company filed GCRM #107 with the Commission which increased the benchmark cost of gas from $5.25 to $6.75, or a commodity increase of $1.50 per dekatherm. Effective November 1, 2003, the Company filed GCRM #108 with the Commission which decreased the benchmark from $6.75 to $5.75, or a commodity decrease of $1.00 per dekatherm. On a total company basis, actual gas costs are computed and compared to the benchmark cost and any difference is allocated to South Carolina based on the current month's sales percentage. Billed vs. Filed rates for the period under review total ($7,296,699).

Demand True-up – These amounts represent the over or under-collection of Demand Charges incurred by the Company as compared to Demand Charges billed and collected monthly from customers. Total Demand Charges incurred are computed monthly and allocated to South Carolina based on Design Day Percentage as approved by the Commission in Order No. 2002-761 dated November 1, 2002, approving new rates and charges issued in Docket No. 2002-63-G. Effective October 2003, the Design Day Factor for demand allocation to South Carolina changed from 22.3% to 15.81% due to the acquisition/merger of North Carolina Natural Gas Co. Permission was granted by the Commission to account for the change in Docket No. 2003-251-G, Order No. 2003-588 (Order granting interim accounting treatment) dated October 1, 2003, even though the methodology for allocation of Demand Costs remains the same as approved in Order No. 2002-761. Effective November 2002, a comparison is made to the demand component included in rates approved by the Commission in Order No. 2002-761 dated November 1, 2002 issued in Docket No. 2002-63-G. Total Demand True-up for the twelve months ended March 31, 2004, represents an over-collection of ($1,745,140). It should be noted that in compliance with Docket No. 95-160-G, Order No. 95-1641 dated August 22, 1995, the Company is reporting Capacity Release activity as required by the Commission. These Capacity Release Credits totaled ($2,708,380), as adjusted by Staff for the review period as shown in Footnote (1) to Audit Exhibit A.

Other PGA Items – Other PGA items consist of an annual "Unaccounted For" True-up, proration adjustments due to cycle billing related to the commodity rate changes at April 1, 2003, and November 1, 2003, and staff adjustments for the prior review period. The April 2003 and November 2003 amounts of ($683,489) and $111,595, respectively, represent proration adjustments for a rate change due to cycle billings. The May 2003 debit of $48,915 represents staff adjustments for an “Unaccounted For” True-up adjustment of $9,277 and a proration adjustment of $39,638 related to a prior review period. The September 2003 adjustment of $97,790 represents the annual “Unaccounted For” True-up. Other PGA Items total ($425,189).

Negotiated Losses – In competition with alternate fuels, the Company's GCRM (Gas Cost Recovery Mechanism) allows it to maintain its industrial load by selling gas at less than the approved tariff resulting in margin losses. These Negotiated Losses for the twelve months ended March 31, 2004 totaled $3,131,538.

Hedging Activity Transfer – In November 2004, the Company transferred to Deferred Cost of Gas account # 253.04 a balance of ($875,471) plus Interest of ($3,371) from account # 191.01 Deferred Account – Hedging Program. This amount represents the Hedging Activity for the 12 months ended March 31, 2003, which was approved by the Commission in Docket No. 2003-4-G, Order No. 2003-556 dated September 15, 2003.

Shared Margin – Effective with new rates approved in Docket No. 2002-63-G, Order No. 2002-761 dated November 1, 2002, the Company is now including 75% of the margin from off-system sales reduced by 25% of capacity release transactions subject to the sharing mechanism set forth in Order No. 2002-761. This net amount is credited to the deferred cost of gas account # 253.04 which results in the Company retaining 25% of the margin from Off-system Sales and 25% of Capacity Release. Order No. 2002-761 also provided that capacity release credits and off-system sales would be allocated to South Carolina using the same design day methodology as approved for fixed demand costs. Total shared margins for the review period were ($662,543).

Accrued Interest – The Company booked interest expense at the rate of 9.25% on the average outstanding balance for the review period. In Docket No. 98-004-G, Order No. 98-618 dated August 11, 1998, the Commission ruled that the actual earned overall rate of return should be utilized in computing Interest on the deferred account balance. In Docket No. 2000-004-G, Order No. 2000-707 dated August 25, 2000, the Commission found that interest on the deferred account be limited to the lower of the authorized overall rate of return or the actual earned overall return. However, the Company cannot compute the actual rate of return until such return is known for the review period. Since Interest is accrued monthly, an annual adjustment is required to restate the accruals at the lower of the actual earned overall rate of return or the approved overall rate of return. The interest credit amount shown for June 2003 of ($48,408) is the result of a staff prior period adjustment of ($70,853) to restate the accruals at the earned overall rate of return for the prior review period netted against the current month's accrual. Staff has also restated the monthly deferred account balances to include this adjustment for the prior review period. For the twelve months ended March 31, 2004, the earned overall Rate of Return of 9.25% was the same as the booked Rate. This resulted in a decrease to booked interest of ($78,393) including Staff adjustments. Interest charges totaled $179,871 for the current review period.

Weather Normalization – The Company began charging Account #253.04 for Weather Normalization effective for the winter heating season of November 1, 1996 through March 31, 1997. Prior to that time, the Company had maintained a separate balance for Weather Normalization in Account #253.09. Weather Normalization is a debit for the current review period of $1,109,866 resulting from warmer than normal weather for the 2003-2004 heating season.

Q. WHAT IS INCLUDED ON AUDIT EXHIBIT A-1?

A. Audit Exhibit A-1 contains the detail of the Company's underground storage and Liquefied Natural Gas (LNG) for the period under review. The Company maintains three separate storage facilities on the Transco System which are detailed as follows: General Storage Service (GSS) located in Pennsylvania, Washington Storage Service (WSS) located in Louisiana and Eminence Storage Service (ESS) located in Mississippi. Exhibit A-1, Page 1 of 7 details GSS storage inventory for the review period. The beginning balance for the review period was 412,199 dekatherms at a total cost of $2,052,831, or a weighted average cost of $4.9802 per dekatherm. Total injections were 5,199,604 dekatherms, including 82,248 dekatherms transferred from North Carolina Natural Gas Co., at a total cost of $27,814,562, or a weighted average cost of

$5.3494 per dekatherm. Withdrawals totaled 4,756,662 dekatherms at a total cost of $26,460,281, or a weighted average cost of $5.5258 per dekatherm. The balance in GSS Storage at the end of the review period totaled 668,252 dekatherms at a total cost of $3,739,501, or a weighted average cost of $5.5959 per dekatherm.

Exhibit A-1, Page 2 of 7 details WSS inventory for the review period. The beginning balance for the review period was 196,020 dekatherms at a total cost of $834,578, or a weighted average cost of $4.2576 per dekatherm. Total injections were 10,218,257 dekatherms, including 2,235,348 dekatherms transferred from North Carolina Natural Gas Co., at a total cost of $51,146,432, or a weighted average cost of $5.0054 per dekatherm. Withdrawals totaled 6,366,742 dekatherms at a total cost of $31,903,369, or a weighted average cost of $5.0049 per dekatherm. The balance in WSS at the end of the review period totaled 3,979,284 dekatherms at a total cost of $20,164,160, or a weighted average cost of $5.0673 per dekatherm.

Exhibit A-1, Page 3 of 7 details ESS inventory for the review period. The beginning balance for the review period was 381,848 dekatherms at a total cost of

$755,627, or a weighted average cost of $1.9789 per dekatherm. Total injections were 316,914 dekatherms at a total cost of $634,468, representing the acquisition/merger of North Carolina Natural Gas Co. There were no withdrawals. The balance in ESS Storage at the end of the review period totaled 698,762 dekatherms at a total cost of $1,390,095, or a weighted average cost of $1.9894 per dekatherm.

Exhibit A-1, Page 4 of 7 details Columbia Gas Storage inventory for the review period. Columbia Gas Storage is a Firm Storage Service (FSS) located in the Pennsylvania, Virginia, West Virginia area provided by Columbia Gas Transmission Company, an interstate pipeline. The beginning balance for the review period was 685,704 dekatherms at a total cost of $2,547,710, or a weighted average cost of $3.7155 per dakatherm. Total injections were 4,460,140 dekatherms, including 223,238 dekatherms transferred from North Carolina Natural Gas Co., at a total cost of $24,684,139, or a weighted average cost of $5.5344 per dekatherm. Withdrawals totaled 4,315,718 dekatherms at a total cost of $23,026,297, or a weighted average cost of $5.3354 per dekatherm. The balance in Columbia Gas Storage at the end of the review period totaled 830,126 dekatherms at a total cost of $4,393,994, or a weighted average cost of $5.2932 per dekatherm.

Exhibit A-1, Page 5 of 7 details the Hattiesburg storage inventory located in Mississippi, for the review period. This inventory is maintained on a combined basis with Piedmont's Tennessee operations. The inventory is allocated 50%-50% between Piedmont's N.C./S.C. operations and Piedmont's Tennessee operations. However, Cost of Gas is accounted for separately among jurisdictions. The beginning balance for the review period was 192,535 dekatherms at a total cost of $1,379,177, or a weighted average cost of $7.1633 per dekatherm. Total injections were 815,202 dekatherms at a total cost of $4,282,468, or a weighted average cost of $5.2533 per dekatherm. Withdrawals totaled 677,323 dekatherms at a total cost of $3,783,867, or a weighted average cost of $5.5865 per dekatherm. The balance in Hattiesburg inventory at the end of the review period totaled 327,342 dekatherms at a total cost of $1,892,811, or a weighted average of $5.7824 per dekatherm.

Exhibit A-1, Page 6 of 7 details activity from Piedmont's LNG facility located near Charlotte, North Carolina, for the review period. The beginning balance for the review period was 265,866 dekatherms at a total cost of $1,241,324, or a weighted average cost of $4.6690 per dekatherm. Total injections were 850,361 dekatherms at a total cost of $4,507,464, or a weighted average cost of $5.3006 per dekatherm. Withdrawals totaled 280,981 dekatherms at a total cost of $1,585,426, or a weighted average cost of $5.6425 per dekatherm. The balance in LNG at the end of the review period totaled 835,246 dekatherms at a total cost of $4,906,953, or a weighted average cost of $5.8749 per dekatherm.

Exhibit A-1, Page 7 of 7 details the activity from the Pine Needle LNG Facility for the review period. Pine Needle is an LNG Facility located in Guilford County, North Carolina and is jointly owned by Piedmont, Transco and several other utilities/investors. Piedmont's ownership portion is 35%. The beginning balance for the review period was 328,900 dekatherms at a total cost of $2,028,414 or a weighted average cost of $6.1673 per dekatherm. Total injections were 2,817,878 dekatherms, including 412,731 dekatherms transferred from Morth Carolina Natural Gas Co., at a total cost of $14,900,894, or a weighted average injection cost of $5.2880 per dekatherm. Withdrawals totaled 2,368,045 dekatherms at a total cost of $13,038,854, or a weighted average cost of $5.5044 per dekatherm. The balance in the Pine Needle LNG inventory at the end of the review period totaled 714,127 dekatherms at a total cost of $3,894,734, or a weighted average cost of $5.4538 per dekatherm.

Q. WHAT IS INCLUDED IN AUDIT EXHIBIT A-2, RISK MANAGEMENT-HEDGING PROGRAM?

A. Audit Exhibit A-2 includes results of the Company's Hedging Program for the review period. The Commission approved an experimental Natural Gas Hedging Program in Docket No. 2001-410-G, Order No. 2002-223 dated March 26, 2002. The Hedging Plan was filed by the Company in response to Commission Order No. 2001-886 dated August 30, 2001, issued in Docket No. 2001-4-G, which directed the Company to file a Hedging Program for Commission approval within 60 days.

As can be seen on Page 7 of the exhibit, the total Risk Management Hedging (Gain)/Loss for the review period is an increase to Cost of Gas of $412,335. Also shown on Page 7, the actual (Gain)/Loss from transactions was $422,590. Also included are the costs to administer the program such as consultant fees, interest charges/credits, etc. For the Cost of Gas months of April 2003 through March 2004, shown on the exhibit are the number of Call Options bought and/or Put Options sold by month at 10,000 dekatherms per contract and the monthly (gain)/loss resulting from the purchase and/or sale of such options. A call option is defined in the Company’s Plan as “an option that gives the buyer the right but not the obligation to buy at a predetermined strike price”. A Put Option is defined in the Company’s plan as “an option that gives the buyer the right but not the obligation to sell at a predetermined strike price”. Also shown is the number of options either exercised or expired. For the review period, the Company sold 217 Put Options, in some instances in combination with the purchase of Call Options. Since the Company receives proceeds from the sale of Put Options, this partially offsets the cost of the Call Options. Also, for the Cost of Gas months of April – June 2003 and March 2004, the Company exercised option contracts for the purchase and sale of 73 gas futures contracts at a net gain of ($397,890). Beginning in June 2003, the Company purchased option contracts for the Cost of Gas months of November 2003 through March 2004. By the end of the review period in March 2004, the Company had purchased option contracts through the Cost of Gas months of October 2004. For the months of April – October 2003, the hedgable volume for the review period was established in the "Hedge Strategy Development" portion of the Hedging Plan developed by Risk Management, Inc. and approved by the Commission in Docket No. 2001-410-G. The volume was based on normalized purchases calculated from budgeted sales amounts for South Carolina. Beginning in November 2003, the Company computed hedgable volume based on normalized sales from the Company's latest rate case, Docket No. 2002-63-G. For the review period the Company hedged 50% of its authorized hedgable volume. The Company was authorized to hedge up to a maximum of 60% of Natural Gas Supplies according to the Hedging Plan as approved by the Commission in the above referenced order.

Also included on Audit Exhibit A-2 is monthly interest amounts calculated on the approved overall rate of return of 10.39% in Docket No. 2002-63-G. This rate is in compliance with the "Operations Manual" portion of the Hedging Plan developed by Risk Management, Inc. and approved by the Commission in Docket No. 2001-410-G, which states "The approved cost of capital will be applied to funds (positive or negative) placed in trading accounts monthly".

Q. WHAT ARE STAFF'S FINDINGS WITH RESPECT TO ACCOUNT #253.04?

A. Staff analyzed the balance of $($1,400,529) included in Account #253.04 at March 31, 2004, and has adjusted that amount as follows:

(1) Staff adjusted June 2003 Accrued Interest to include an interest adjustment recommended by Staff in Docket No. 2003-4-G of ($70,853) to reflect the Actual Earned Overall Rate of Return of 7.29%, for the twelve (12) months ended March 31, 2003.

(2) Staff adjusted "Other PGA Item" to adjust Proration Adjustments by a credit of ($4,150) to reflect the proper South Carolina sales Allocation Factor for the month of November 2003.

(3) Staff adjusted the Billed/Filed calculation by a credit of ($40,190) to reflect a correction in the billed rate for certain rate schedules for the month of December 2003.

(4) Staff adjusted the Shared Margin calculation by a credit of ($112,417) to reflect a correction in the amount of Shared Margin charged to account # 253.04 from off-system sales and Capacity Release for the month of February 2004. Staff also proposes to adjust total Company Capacity Release by $76,606 which reduces South Carolina allocated Shared Margin by $3,028. Staff's total adjustment to Shared Margin for February 2004 is ($109,389).

(5) Staff adjusted Shared Margin by $8,510 to reflect a reduction in the amount of Shared Margin from off-system sales for the months of November 2003 and March 2004.

(6) Normally, Staff would adjust Interest for the current review period to the lower of the booked overall Rate of Return or the Actual Earned overall Rate of Return. However, the booked and earned returns of 9.25% were the same for the 12 months ended March 31, 2004. However, including Staff's adjustment to Interest in June 2003 (Adj. #1) and including the effects of all other Staff adjustments results in an additional reduction to Interest of ($7,540). Total interest adjustments by Staff is a credit of ($78,393)

The net effect of the above adjustments is an increase to the over-collection at March 31, 2004 of ($223,612). It is Staff's opinion that the adjusted balance at March 31, 2004 of ($1,624,141), before including the net hedging activity, fairly represents the over-collection by the Company and that the amount is accurately stated and in compliance with Commission Order No. 88-294. After including the net effect of Hedging Activity for the current review period, as shown on Audit Exhibit A-2, Staff has computed the Net Over-collection to be ($1,211,806).

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.